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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	Rulemaking 19-11-009 (Filed November 7, 2019)

SECOND REVISED TRACK 3B.2 PROPOSALS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

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Dated: February 26, 2021

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I. INTRODUCTION

On December 11, 2020, Assigned Commissioner Liane M. Randolph issued the *Assigned Commissioner's Amended Track 3B and Track 4 Scoping Memo and Ruling* ("Amended Scoping Memo"). The Amended Scoping Memo modifies the previous schedule for Track 3B of this proceeding, bifurcating it into two tracks: Track 3B.1 and Track 3B.2. Per the schedule set forth in the Amended Scoping Memo, Pacific Gas and Electric Company ("PG&E") and other parties submitted revised Track 3B.2 proposals on December 18, 2020, and comments on revised Track 3B.2 proposals were submitted on January 15, 2021.[1] Workshops on revised Track 3B.2 proposals were conducted in early February 2021.

Pursuant to the schedule set forth in the Amended Scoping Memo, and in accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), PG&E now hereby submits its second revised Track 3B.2 proposals ("Proposals"). PG&E's revised Proposals are set forth in Attachment 1 hereto.

II. CONCLUSION

PG&E appreciates the opportunity to provide its revised Proposals on Track 3B.2 issues. PG&E looks forward to working with the Commission and stakeholders to further develop and explore the revised Proposals and other Track 3B.2 proposals.

[1] Amended Scoping Memo, pp. 4-5.

Respectfully Submitted,

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Attachment 1
to
SECOND REVISED TRACK 3B.2 PROPOSALS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

PG&E Second Revised Proposals on Track 3B.2 Issues in Rulemaking 19-11-009

Prepared by:

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PG&E Second Revised Proposals on Track 3B.2 Issues in Rulemaking 19-11-009

I. INTRODUCTION

PG&E submitted its "Slice-of-Day" and "Contract Hedge" proposals on December 18, 2020, in Track 3B.2 of Rulemaking 19-11-009. PG&E has gathered feedback from numerous stakeholders since submitting the original proposals and drawn on elements of other submitted proposals to revise and expand on the December 18 proposals. These revisions and expansions are detailed in the second revised Track 3B.2 proposals, set forth below.

II. PG&E'S SECOND REVISED SLICE-OF-DAY PROPOSAL

PG&E expands on the following sections of the Slice-of-Day proposal:

- Determining Seasons and Slices
- Resource Counting
- Requirements and Resource Stacks
- Need Determination and Allocation
- Must-Offer-Obligation

1. Determining Seasons and Slices

PG&E's original "Slice-of-Day" proposal recommended focusing on meeting load in all hours of the day while counting resources when they are available to meet load. The proposal recommended doing this by breaking the day up into "slices" that would be grouped on a seasonal basis. The original proposal sketched an illustrative example for how to construct seasons and slices, noting that additional work was needed to develop a framework for determining seasons and slices. PG&E outlines a framework to use in determining the seasons and slices below.

a. Objectives

PG&E has outlined several objectives for consideration when establishing seasons and slices. PG&E recommends using these criteria to assess season and slice options. The objectives / criteria include:

- Reliability: Select seasons and slices that meet the desired level of reliability; this effort must be coordinated with establishing resource counting methodologies.
- Operational Considerations: Results in manageable operational impacts such as allowing for typical maintenance outage windows for resources.
- Integrate Variable and Energy-Limited Resources: Use variable resource production data to integrate those resources in a way that optimizes their participation.
- Integrate Storage Resources: Establish a structure that accounts for capacity to meet energy storage charging needs.
- Revenue Sufficiency: Provides revenue sufficiency for fossil units needed for reliability purposes, but also results in lower utilization of those units to meet state policy goals.
- Reasonable Administrative Burden: While it could be tempting to establish many seasons and slices, a reasonable number is needed to ensure a manageable administrative burden associated with resource adequacy ("RA") showings and compliance. This includes the effort in transacting between market participants, as more complex requirements will impact the effort needed to contract to meet the requirements.

b. Data Considerations

PG&E used data from the following sources in developing the framework for determining seasons and slices.

- Load: *2019 CEC IEPR CAISO System Hourly Forecast, Mid-Mid* data for 2021 forecast year, which is a 1-in-2 load forecast. The California Energy Commission ("CEC") Integrated Energy Policy Report ("IEPR") monthly load forecast is currently used in setting RA requirements; therefore, PG&E believes the hourly load forecast should be used in setting requirements for the seasons and slices.

Updates to the CEC IEPR forecast are made every two years, with interim updates made in off-years. Should the Commission move forward with the "Slice-of-Day" proposal, PG&E recommends using the latest available hourly load forecast data.[1]

- <u>Resource Production</u>: *2018-2019 CAISO OASIS Resource Generation Data*. Resource generation data is important for establishing seasons and slices, as well as establishing exceedance values. PG&E has used 2018-2019 data for the framework discussion below, but additional years of data are likely to be relevant. PG&E seeks feedback from stakeholders on how many years of data should be used, particularly for solar and wind resources.
- <u>Resource Values</u>: *2021 CAISO NQC List*. While this data was not used for determining seasons and slices, it was used for illustrating resource counting for different resources types.

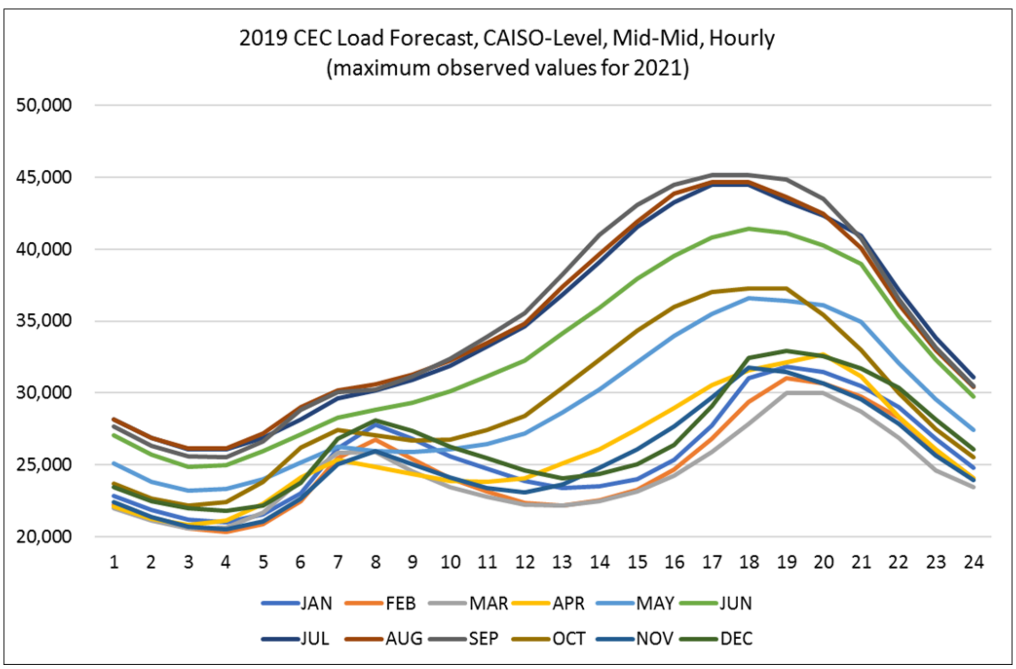
[1] Currently, RA requirements are based on a 1-in-2 load forecast with a 15 percent planning reserve margin. These values will likely need to be adjusted depending on the resource counting rules adopted and desired level of reliability. These considerations are essential to the process of adopting a new RA structure.

c. Determining Seasons

(1) Load

To establish seasons, using the load data is a reasonable starting point. Given the sub-day granularity of the framework, hourly data is needed. The CEC publishes system and Transmission Access Charge ("TAC")-level hourly load forecasts as part of the IEPR. PG&E has pulled the 2019 IEPR California Independent System Operator Corporation ("CAISO")-level hourly mid-mid load forecast data for 2021 and used this data to create monthly forecasts based on the maximum observed values in each hour for each month. The maximum approach is intended to replicate the process that is currently followed for establishing monthly RA requirements in which maximum observed values for each month form the system-level requirement. The following graph shows these results:

Figure 1: 2019 CEC Load Forecast, CAISO-Level, Mid-Mid, Hourly Forecast: Maximum Observed Values for 2021



Notably, there are three months of the year (July, August, September) tightly grouped with a similar load shape at the top of the graph and there are several months tightly grouped with a similar load shape at the bottom of the graph (November – April). May, June and October fall in between and do not clearly fit into either grouping.

To explore the load data further, a heat map can also be useful for identifying patterns. In Figure 2 (below) the heat map colors reflect relative values of the data in Figure 1. For instance, the darker green colors are the lowest values in the table, the reddish values are the highest values in the table, and yellow and orange colors fall in between. Figure 2 indicates the load data for June is more closely aligned with loads above 40,000 megawatts ("MWs"), representative of the months of July – September, so it may make sense, from a load perspective, to include June with these months to establish a "Summer" season. Figure 2 also confirms the information in the graphs that the months of November – April are similar and could likely be grouped together into a "Winter" season from a load perspective. This leaves May and October as transitional or shoulder months. It may make sense to group these months into a "Shoulder" season, but the resource generation data should also be examined.

Figure 2: 2019 CEC Load Forecast, CAISO-Level, Mid-Mid, Hourly Forecast: Maximum Observed Values for 2021

HE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	22,853	22,205	21,981	22,107	25,085	27,075	28,164	28,145	27,695	23,685	22,375	23,439
2	21,844	21,224	21,110	21,251	23,825	25,707	26,845	26,876	26,321	22,630	21,349	22,459
3	21,166	20,560	20,579	20,824	23,192	24,832	26,053	26,117	25,605	22,134	20,701	21,951
4	20,991	20,349	20,645	21,122	23,314	24,974	26,089	26,153	25,527	22,422	20,487	21,782
5	21,552	20,886	21,695	22,293	24,013	25,954	26,900	27,206	26,620	23,798	21,047	22,174
6	23,016	22,439	23,954	24,134	25,170	27,137	28,168	29,038	28,841	26,219	22,643	23,758
7	26,146	25,461	25,835	25,364	26,239	28,298	29,617	30,163	30,074	27,429	25,032	26,810
8	27,790	26,769	25,870	24,837	25,981	28,829	30,189	30,604	30,228	27,058	25,968	28,106
9	26,779	25,410	24,526	24,332	25,891	29,289	30,896	31,285	31,130	26,678	25,016	27,345
10	25,607	24,034	23,436	23,875	26,082	30,129	31,890	32,255	32,375	26,729	24,122	26,279
11	24,742	23,134	22,779	23,792	26,451	31,175	33,222	33,470	33,904	27,441	23,393	25,435
12	23,849	22,362	22,200	24,062	27,163	32,254	34,657	34,813	35,575	28,378	23,092	24,611
13	23,393	22,151	22,164	25,069	28,630	34,166	36,813	37,385	38,245	30,362	23,609	24,062
14	23,524	22,521	22,440	26,087	30,245	35,931	39,075	39,636	40,971	32,294	24,805	24,364
15	23,988	23,288	23,118	27,487	32,119	37,957	41,578	41,895	43,101	34,314	26,084	25,015
16	25,323	24,638	24,247	28,961	33,970	39,520	43,288	43,857	44,469	35,971	27,640	26,408
17	27,697	26,836	25,917	30,561	35,467	40,841	44,485	44,679	45,149	37,022	29,675	29,094
18	31,056	29,374	27,839	31,605	36,618	41,421	44,477	44,653	45,184	37,253	31,750	32,411
19	31,848	30,999	30,008	32,112	36,419	41,104	43,306	43,644	44,861	37,271	31,462	32,903
20	31,434	30,635	29,975	32,669	36,109	40,258	42,359	42,461	43,520	35,420	30,642	32,552
21	30,487	29,771	28,717	31,133	34,915	38,975	40,923	40,064	40,737	32,992	29,542	31,691
22	28,985	28,293	26,882	28,350	32,087	35,326	37,125	36,160	36,527	29,999	27,862	30,375
23	26,801	26,033	24,580	26,056	29,558	32,323	33,849	32,978	33,169	27,478	25,674	28,176
24	24,804	24,030	23,430	24,060	27,420	29,714	31,106	30,397	30,459	25,506	23,917	26,070

(a) Gross Peak Load versus Net Peak Load

PG&E's original proposal was based on a gross peak load view compared to a net peak load view that would net out solar and wind resources. Several stakeholders expressed interest in the use of net peak load data as part of PG&E's proposal and wanted to understand the impact of a change from a gross peak load view to a net peak load view. PG&E's perspective is that either load view could be used in the "Slice-of-Day" framework each with advantages and disadvantages to be considered before a decision is made. A critical consideration under either approach is ensuring a desired level of reliability, which should be linked to the resource counting framework. Under a net peak load view, a more conservative resource counting for solar and wind resources might be warranted, as the resource profile would reduce load requirements one-for-one. The gross peak load view might enable a less conservative resource counting value.

Table 1: Gross Peak Load versus Net Peak Load Approach

	Gross Load	***Net Load***
Advantages	• Preserves specific net qualifying capacity ("NQC") value for solar and wind resources across seasons and slices, facilitating transactions. • Creates greater revenue sufficiency for units needed for reliability as they are likely to get RA payments for some slices, but would not need to generate for the full slice (as some solar and wind production would still occur at the edges).	• Simplifies season and slice framework, as seasons and slices do not have to be determined based on solar and wind production data. • Solar and wind resources could benefit by not losing some production around the margins of the slices, although this assumes the counting approach for solar and wind resources would be the same under the gross peak and net peak

		approaches.
Disadvantages	• Solar and wind production data need to be considered when determining the slices, adding some complexity to the task.	• Creates more revenue sufficiency for units needed for reliability but requires the more conservative counting approach for solar and wind resources. • An 8,760 generation profile for solar and wind resources is needed for load serving entities ("LSEs") to offset their load. • Enforcement could involve checking a separate set of solar and wind values.
Unclear	• Solar and wind RA value: resources could be worse off by losing some production around the margins of the slices, but if the counting approach for solar and wind resources is not the same under the gross peak and net peak approaches it could be a net gain.	• Solar and wind RA value: resources could benefit by not losing some production around the margins of the slices, but if the counting approach for solar and wind resources is not the same under the gross peak and net peak approaches it could be a net loss.

The gross peak load view is used throughout the remainder of the proposal revisions and enhancements to illustrate how they work and indications about differences under a net peak load approach are highlighted.

(2) Resource Generation Data

(a) Initial Observations on Resource Technology Type

To optimally integrate variable and energy-limited resources, it is helpful to distinguish between resource types that need additional consideration when establishing seasons and slices. Energy-limitations is a useful way to identify the resources that need additional study. Resources that have few energy-limitations (thermal) or that are baseload (nuclear, geothermal, biomass) can generally have the same RA value for every season and slice.[2] Those resources with more complex energy-limitations (solar, wind, hydroelectric) will have RA values that differ between seasons (solar, wind, hydroelectric) or slices (solar and wind). Hydroelectric is distinguished from solar and wind as it generally can be dispatched at any point during the day but is limited on a seasonal basis due to fuel (e.g. water) availability.

(b) Solar

Solar is the largest variable and energy-limited resource and is forecasted to grow substantially in the coming years.[3] Figure 3 is a heat map of solar generation data based on a 50 percent exceedance[4] for 2018-2019 generation data.[5]

[2] PG&E recognizes that thermal and biomass have some use limitations, e.g. noise and emissions constraints. PG&E welcomes feedback from stakeholders on limitations that should be considered for these resources when establishing seasons, slices, or resource counting values.
[3] *See* Table 5: New Resource Buildout of 2019-2020 RSP, "2019-2020 Electric Resource Portfolios to Inform Integrated Resource Plans and Transmission Planning," Decision ("D.") 20-03-028, issued April 6, 2020, available: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M331/K772/331772681.PDF
[4] The X percent exceedance level of a resource's production profile is the MWh generation amount that the resource is expected to produce at least X percent of the time.
[5] Note: Figure 3 differs slightly from the figure used in the Track 3B.2 workshop on February 8, 2021. The figure used in the workshop was based on an average of observed values, while Figure 3 is based on the median of observed values. A 50 percent exceedance uses median values, so Figure 3 should be used.

Figure 3: CAISO Solar Production Data, 2018-19, 50% Exceedance

HE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-
7	-	37	-	256	1,089	1,624	782	296	58	-	165	-
8	911	2,162	1,332	3,131	4,617	5,621	4,200	3,309	2,541	1,116	2,488	1,180
9	3,811	5,915	5,289	6,724	7,575	8,409	7,467	7,482	6,986	5,287	5,705	3,721
10	5,618	7,696	7,437	8,470	8,962	9,520	9,062	9,200	9,032	7,908	7,228	5,242
11	6,252	7,837	8,208	9,257	9,688	10,132	9,741	9,910	9,726	8,990	7,575	5,862
12	6,746	7,819	8,377	9,441	9,902	10,486	10,128	10,255	10,037	9,093	7,493	6,050
13	6,744	7,971	8,360	9,448	9,880	10,558	10,237	10,273	10,028	9,036	7,422	6,163
14	6,647	7,639	8,100	9,194	9,778	10,528	10,102	10,252	10,036	9,019	7,334	5,506
15	5,978	7,307	7,927	9,095	9,596	10,385	9,852	10,089	9,912	9,049	6,537	5,077
16	4,056	6,231	7,244	8,630	9,095	9,909	9,343	9,737	9,444	8,560	3,583	2,736
17	814	2,745	5,346	7,690	8,137	9,221	8,709	8,852	8,393	6,410	422	266
18	-	153	2,830	5,735	6,640	7,855	7,235	6,863	5,511	2,041	-	-
19	-	-	641	2,035	3,330	4,810	4,217	2,847	1,112	39	-	-
20	-	-	-	79	381	1,089	853	267	-	-	-	-
21	-	-	-	-	-	-	-	-	-	-	-	-
22	-	-	-	-	-	-	-	-	-	-	-	-
23	-	-	-	-	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	-	-	-	-	-

Figure 3 demonstrates that June has the highest level of generation for solar and therefore it would make sense to include in the "Summer" season (from the solar resource perspective). Generation falls off in September, particularly in the morning and evening periods, and accelerates in October, making October an unlikely month to include in the "Summer" season from the solar resource perspective. Solar also has reasonable levels of generation in May, likely making May a month to include in the "Summer" season, even though Figure 1 showed that loads are lower in May.

(c) Wind

Figure 4 illustrates the heat map for wind using data based on a 50 percent exceedance for 2018-2019 generation data.

Wind produces the most in the evening, overnight, and early morning hours from April through September, with May through August being the highest generation months. November through January have lower generation, with moderate generation in October, February and

Figure 4: CAISO Wind Production Data, 2018-19, 50% Exceedance

HE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	654	1,819	1,598	3,034	3,423	3,565	3,387	3,248	2,628	1,521	592	738
2	619	1,817	1,598	2,893	3,330	3,579	3,252	3,126	2,403	1,363	643	695
3	564	1,615	1,608	2,888	3,283	3,386	3,103	2,923	2,188	1,210	626	732
4	552	1,523	1,696	2,989	3,112	3,231	2,983	2,704	2,064	1,245	611	706
5	593	1,348	1,624	2,919	3,013	2,922	2,735	2,436	1,841	1,329	589	728
6	548	1,334	1,541	2,674	2,931	2,771	2,361	2,253	1,644	1,381	513	742
7	554	1,333	1,456	2,524	2,709	2,330	2,127	2,023	1,450	1,258	526	719
8	549	1,355	1,334	2,112	2,379	1,952	1,832	1,700	1,225	921	512	746
9	505	1,289	1,377	1,786	2,267	1,713	1,367	1,356	1,110	832	499	686
10	493	1,326	1,432	1,811	1,938	1,546	1,087	1,199	915	712	561	697
11	521	1,372	1,437	1,712	1,825	1,373	928	1,017	818	722	548	699
12	525	1,564	1,264	1,777	1,677	1,357	850	983	717	720	534	643
13	515	1,543	1,276	1,694	1,879	1,378	829	1,070	794	858	533	671
14	593	1,569	1,482	2,088	2,031	1,498	1,024	1,345	953	775	516	859
15	626	1,581	1,734	2,264	2,369	1,830	1,383	1,731	1,097	854	550	940
16	620	1,700	1,894	2,676	2,869	2,308	1,745	2,015	1,316	939	512	771
17	575	1,765	1,948	2,838	3,322	2,667	2,161	2,458	1,636	1,003	470	691
18	589	1,727	1,829	2,896	3,451	2,948	2,650	2,820	1,890	1,006	516	744
19	635	1,781	1,752	3,019	3,476	3,281	3,052	3,050	2,191	1,079	602	772
20	651	1,906	1,916	3,048	3,437	3,483	3,241	3,300	2,590	1,139	602	780
21	607	1,981	1,936	2,967	3,374	3,650	3,500	3,468	2,660	1,421	601	779
22	560	1,930	1,928	2,969	3,427	3,660	3,430	3,449	2,536	1,503	594	779
23	560	1,897	1,747	3,023	3,482	3,690	3,500	3,274	2,440	1,462	613	771
24	565	1,783	1,709	3,127	3,487	3,624	3,435	3,300	2,461	1,488	582	688

March. Including September in the "Summer" season would result in slightly lower RA value for wind resources in June through August.

(d) Hydroelectric

Figure 5 illustrates the heat map for hydroelectric using data based on a 50 percent exceedance for 2018-2019 generation data.

Hydroelectric is unique relative to solar and wind resources, as it has the ability to dispatch across all hours of the day but has seasonal constraints due to water availability. Therefore, hydroelectric can help to determine the seasons but should not be considered when determining slices. Figure 5 indicates that hydroelectric generation is higher from May through August, with moderate generation in March, April, and September. October through February have the lowest generation levels.

Figure 5: CAISO Hydro Production Data, 2018-19, 50% Exceedance

HE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	1,891	2,009	2,922	3,372	3,422	3,616	3,401	2,953	2,579	1,735	1,656	1,831
2	1,812	1,952	2,865	3,381	3,310	3,584	3,173	2,726	2,429	1,641	1,462	1,689
3	1,762	1,921	2,820	3,351	3,230	3,509	3,037	2,683	2,384	1,608	1,444	1,588
4	1,756	1,946	2,766	3,319	3,219	3,447	2,978	2,612	2,309	1,607	1,444	1,563
5	1,869	2,003	2,878	3,419	3,404	3,520	2,990	2,692	2,387	1,657	1,519	1,743
6	2,075	2,409	3,004	3,578	3,555	3,682	3,079	2,874	2,609	1,899	1,781	2,108
7	2,410	2,808	3,107	3,636	3,456	3,601	3,218	3,058	2,793	2,256	2,008	2,287
8	2,451	2,679	3,203	3,518	3,207	3,203	3,065	2,858	2,644	2,257	1,871	2,256
9	2,007	2,206	2,901	3,250	2,958	2,872	2,903	2,583	2,205	1,796	1,433	1,903
10	1,780	2,004	2,739	3,151	2,814	2,787	2,859	2,507	2,163	1,538	1,388	1,688
11	1,713	1,921	2,569	3,018	2,724	2,847	2,927	2,666	2,179	1,534	1,378	1,568
12	1,665	1,863	2,490	2,989	2,697	2,918	3,000	2,776	2,220	1,514	1,330	1,439
13	1,656	1,788	2,314	2,946	2,691	3,010	3,266	2,852	2,256	1,529	1,303	1,410
14	1,665	1,851	2,303	2,924	2,779	3,025	3,433	3,133	2,387	1,564	1,393	1,453
15	1,725	1,830	2,296	3,020	2,804	3,126	3,608	3,275	2,462	1,586	1,480	1,588
16	1,920	2,084	2,368	3,105	2,855	3,253	3,836	3,465	2,593	1,697	1,935	2,006
17	2,432	2,517	2,555	3,133	3,057	3,480	4,091	3,756	2,882	1,982	2,548	2,731
18	3,040	3,088	2,892	3,369	3,318	3,881	4,415	4,097	3,266	2,757	2,813	3,182
19	3,088	3,294	3,486	3,730	3,665	4,238	4,663	4,579	3,633	3,074	2,769	3,199
20	2,895	3,140	3,521	3,973	4,290	4,580	4,867	4,629	3,670	3,042	2,652	3,126
21	2,704	2,977	3,510	3,977	4,351	4,494	4,751	4,398	3,445	2,827	2,410	2,833
22	2,331	2,649	3,305	3,802	4,166	4,206	4,432	4,089	3,177	2,463	2,109	2,538
23	2,174	2,349	3,104	3,547	3,970	3,940	4,117	3,643	2,929	2,150	1,920	2,233
24	1,979	2,219	2,912	3,403	3,641	3,797	3,625	3,230	2,665	1,923	1,696	1,943

(e) Key Takeaways for Seasons

In reviewing the load data, PG&E found that the highest loads are in the months of June through September and the months with the lowest loads are November through April, and the months of May and October fall somewhere in between. The following table also summarizes the level of generation for solar, wind and hydroelectric resources.

Table 2: Summary of Generation Output by Resource Type

Resource Type	***High Output***	***Moderate Output***	***Low Output***
Solar	June - September	April, May (Trending High), and October	November – March
Wind	May - August	February - April and September - October	November - January
Hydroelectric	May - August	April and September	October - February

(f) An Example of Options for Seasons

Provided in Table 3 (below) are potential options for seasons based on the data discussed thus far. These potential options are a reflection of the data set used for the analysis. Should the seasonal options concept move forward, PG&E believes more data should be used to inform the process and stakeholder input. Table 3 outlines possible options based on the limited data analysis.

Table 3: Season Options

	Season 1	**Season 2**	**Season 3**
Option 1	Summer: June - September	Winter: November – April	Shoulder: May and October
Option 2	Early Summer: May – July	Late Summer: August – October	Winter: November - April
Option 3	Summer: May - August	Winter: November – April	Fall: September - October

Option 1 aligns closely to load forecasting data. The highest load months are June – September, forming the "Summer" period. The lowest load months are November – April, forming the "Winter" period. May and October fall in between, forming a "Shoulder" period. A benefit of this approach is that it narrows the highest load season to four months and allows for moderate to high levels of production from solar, wind, and hydroelectric during that period. A disadvantage of this approach is that it includes a season with two non-adjoining months, which can be confusing as market participants transition to a new RA structure.

Option 2 better matches resource contributions by grouping May - July, which are high production months for solar, wind, and hydroelectric. A disadvantage of this approach is that it extends the period of high loads to six months, as the requirement in shoulder months like May would align with the highest loads observed during that three-month period. The August – October period could also be problematic, as solar, wind, and hydroelectric production is lower in October. Since resource values would be the same for the season, this season would likely be the tightest supply season.

Option 3 attempts to achieve some of the resource synergies from Option 2, while narrowing the late summer season to September and October.

d. Determining Slices

Although presented serially in this exposition, PG&E notes that determining seasons and slices should be coordinated to ensure a balance between administrative effort and accuracy in determining the level of reliability sought.

Determining slices involves several considerations: (1) using load to set requirements of the slice, (2) resource characteristics, and (3) slice design. The load forecast sets the requirements for each slice. PG&E has set the requirement at the peak load in each slice in the examples below, but a final determination of the requirement (whether set at the peak, average, or some other level) should involve consideration of the planning reserve margin ("PRM") that is used for each slice.

The key resources to consider when setting slices are solar and wind, as they are variable, energy-limited and non-dispatchable (and make up a considerable portion of the overall portfolio). While hydroelectric was considered in setting the seasons, hydroelectric can dispatch throughout the course of the day and therefore could fit into any slice. Baseload resources generally have the same value throughout the day and most thermal resources can operate throughout the course of the day as well. PG&E has incorporated energy storage into slice design by setting the initial slice length to four hours.

Lastly, some considerations for slice design are whether there is a need to maintain a consistent length of slice and maintain the same blocks across seasons. While PG&E presents examples below with the same length of slice, this could be changed to accommodate administrative simplicity. Slice blocks may also need to change across seasons to account for seasonal load and resource changes.

(1) Slice Examples

The following information is intended as illustrative examples, not PG&E's recommendation on the slices. Figure 6 represents the summer load forecast for a June through September summer season. The slices have been set to four hours to accommodate the current RA counting rules of 4-hour duration. The requirements have been set at the maximum observed value for each of the slices.

The slice periods in Figure 6 have been selected based on solar and wind data from Figure 7 and Figure 8.

Figure 6: Slice Examples

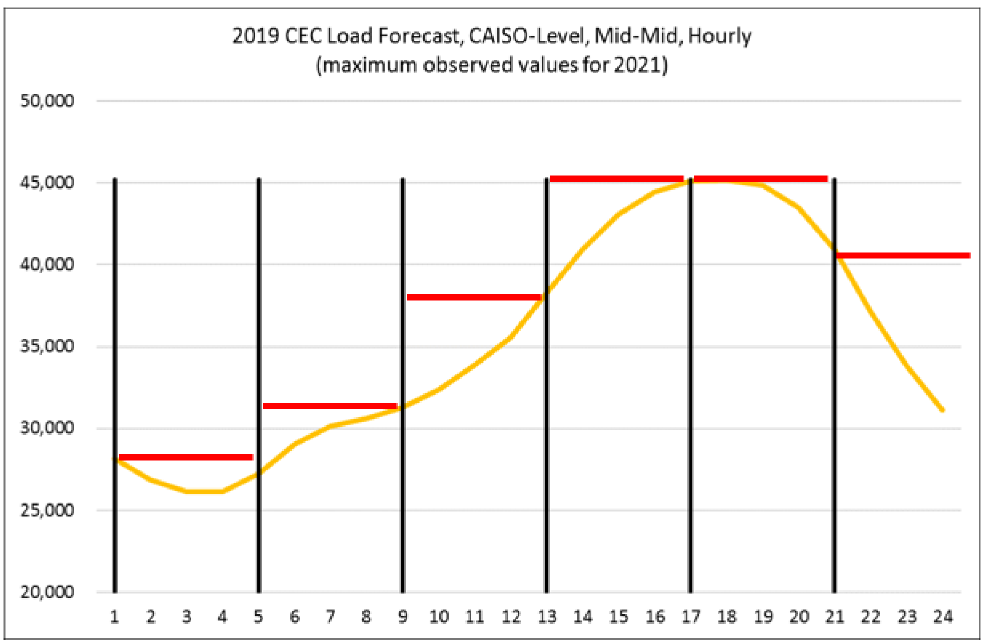


Figure 7: Solar Profiles

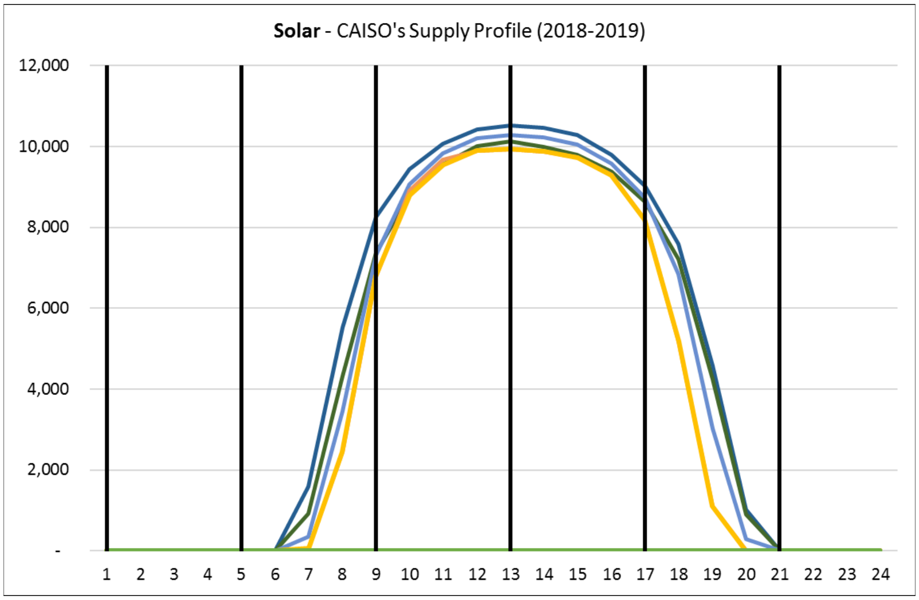
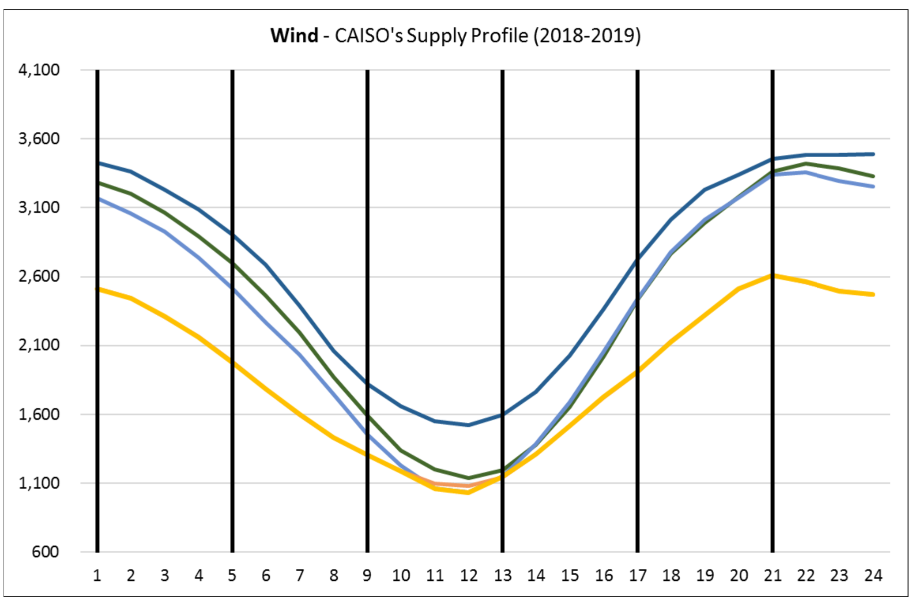


Figure 8: Wind Profiles



As shown, slices 3 and 4 were selected to optimize output from solar resources, while also including slices of moderate wind resource generation. Note that slices 2 and 5 would have very little, if any, solar generation included given the steep ramp up and ramp down of solar in those slices.

While dependent on the final RA counting methodology, this approach is likely to provide a more accurate representation of the contribution of solar and wind resources to meeting load in more hours of the day than currently captured under the effective load carrying capability ("ELCC"). The aggregated ELCC value for solar in September in the 2021 NQC list is 1,679 MWs and the aggregated ELCC value for wind in September is 865 MWs.

2. Resource Counting

a. Objectives

PG&E has outlined the following objectives for resource counting rules:

- Simplify the counting rules.
- Address the need for more than one RA value for solar and wind resources.
- Ensure physical and resource-specific characteristics are considered and incorporated.

PG&E believes that an exceedance-based approach for most resources is the most appropriate way to meet these objectives, as it meets the first two objectives and can be modified to address the last one. An exceedance-based approach could also be coordinated with the CAISO's unforced capacity ("UCAP") proposal by aligning on data to use for exceedance and UCAP. Lastly, counting rules are a critical input to any large RA reform. Should the Commission elect to move forward with the Slice-of-Day framework, counting rules should be used to inform specific definitions for each season and slice.

b. Resource Summary

The following table summarizes the current counting methodology by resource relative to options for an exceedance-based approach. Note that each resource would have a season/slice value under the Slice-of-Day framework.

Table 4: Summary of Current Counting Approaches and Options for Proposed Approaches

	Current Counting Approach	***Options for Proposed Approach***
Solar/Wind	ELCC	X percent exceedance, with weighting; generation-based
Dispatchable Thermal	PMax	PMax w/ exceedance-based thermal derates; generation or bid-based
Hydroelectric	Exceedance; bid-based; monthly value	Existing approach by season and slice
Non-Dispatchable	Average generation output during peak	X percent exceedance; generation-based
Storage	PMax measured over a four-hour period	Maximum capability measured over a slice; requires LSE to show capacity to charge the storage
Hybrid	Renewable is derated for the capacity needed for charging	Renewables and storage are treated separately with possible adjustment for excess energy production by renewable resource
Imports	Contracted Amount	Contracted Amount

An exceedance-based methodology is resource-specific, so each resource would get a unique value based on how it has performed over the historical period in question. Note that new resources would receive a resource average until sufficient historical data is available for the exceedance calculation. Select resource types are addressed in greater detail below.

c. Solar/Wind

PG&E proposes moving to an exceedance-based approach for solar and wind resources. Such an approach would enable geographic and technology specificity, as each project would receive a unique exceedance value. It would allow for balancing of the exceedance percentage with the PRM. For example, a more conservative exceedance percentage could be accompanied with a lower PRM and vice versa. It could also allow for weighting normal conditions with more extreme values to generate a more conservative perspective. This would be similar to how an exceedance-based methodology is currently applied for hydroelectric in which a 50 percent exceedance is weighted at 80 percent and a 10 percent exceedance is weighted at 20 percent. An exceedance-based approach would enable identification of an RA value for solar and wind resources at every hour of the year. It also provides opportunities to integrate planning assumptions between the RA and Integrated Resource Planning ("IRP") proceedings. The IRP profiles are expected value profiles, similar to a 50 percent exceedance, if the RA proceeding were to use a different exceedance level, this could be reflected in IRP assumptions to narrow differences between the proceedings. Lastly, if a net peak load approach were pursued, an exceedance approach would be needed to develop a solar/wind curve to subtract from the gross peak load curve.

d. Dispatchable Thermal

Dispatchable thermal would use a hybrid PMax / exceedance approach that would derate the PMax values during the hottest (temperature) times of the year to account for thermal derates experienced at those times. This would address issues associated with a full exceedance approach that could capture hours when the unit did not generate (if generation data were used), unfairly biasing the RA value downward. It would also address a shortcoming in the current approach that does not account for thermal derates. The specifics of which hours to use in assessing the decrements would still need to be developed.

e. Storage

Storage would shift from the current approach of measuring the PMax over a four-hour period to measuring the maximum capability over a slice, although PG&E has proposed that the slices around the gross load peak and net load peak remain four-hour slices to accommodate storage. To account for the capacity needed for energy storage charging, LSEs that have energy storage in their portfolio would be required to include additional capacity in another slice to account for the charging. While detailed in the must-offer-obligation ("MOO") section below, PG&E is not proposing that the energy storage unit would be bound operationally to actually charge at that time, but rather show that sufficient capacity exists for planning purposes.

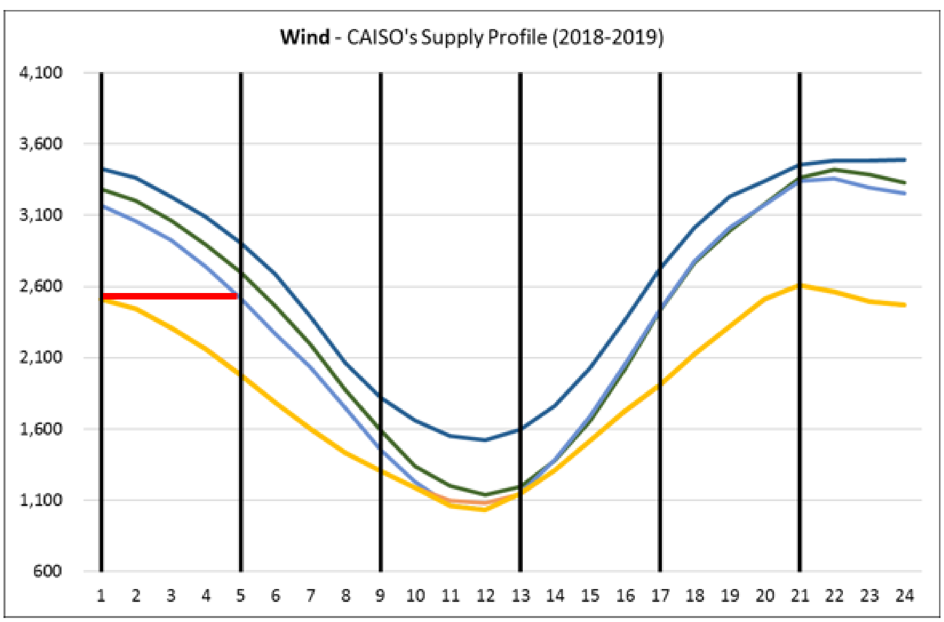
f. Hybrid

By incorporating the requirement that LSEs show sufficient capacity for charging standalone storage, the Slice-of-Day approach places hybrid resources on more equal footing with standalone storage. Hybrid resources currently result in decrements to renewable output, while standalone storage units do not have to account for their charging needs. By including the requirement that LSEs account for charging needs of all storage units, PG&E believes that hybrid units could be treated as separate units. With regards to counting rules, a similar approach could be taken with storage as with dispatchable thermal, namely, a PMax / exceedance value adjusted for actual performance.

g. Solar / Wind Slice Values

As discussed above, an exceedance approach for wind and solar would facilitate setting

Figure 9: Wind Profiles for Setting Slice Values

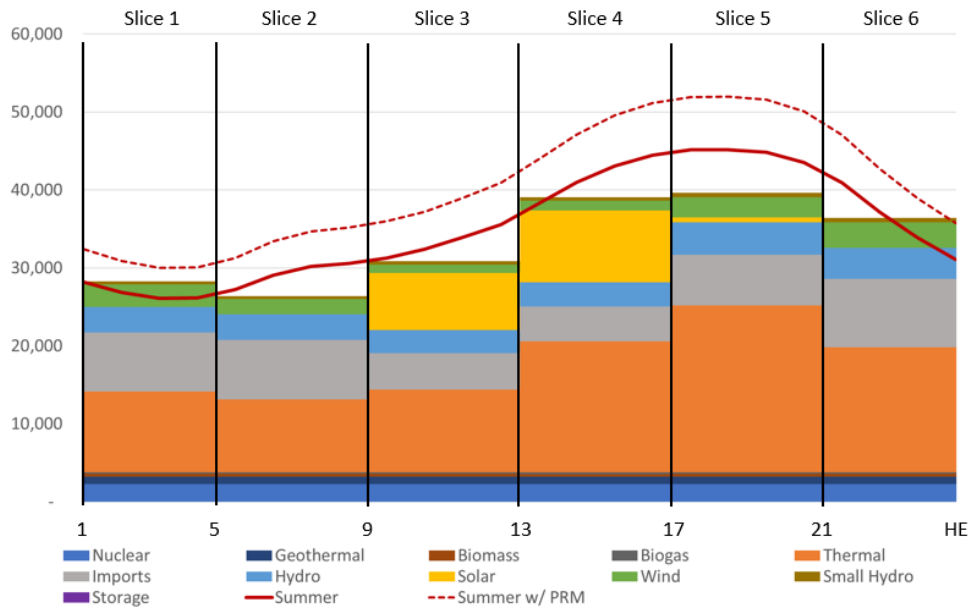


the wind and solar value to be more or less conservative based on the PRM and loss of load expectation ("LOLE") analysis. Figure 9 illustrates how the slice value might be determined for a wind slice. Each of the line graphs represents a wind profile for the summer months (June – September), with September being the bottom yellow line. The slice value could be set to account for the desired level of uncertainty – with the red line in Figure 9 being drawn to represent a value below the median.

3. Requirements and Resource Stacks

Figures 10, 11, and 12 are intended to show how all of the pieces of the Slice-of-Day

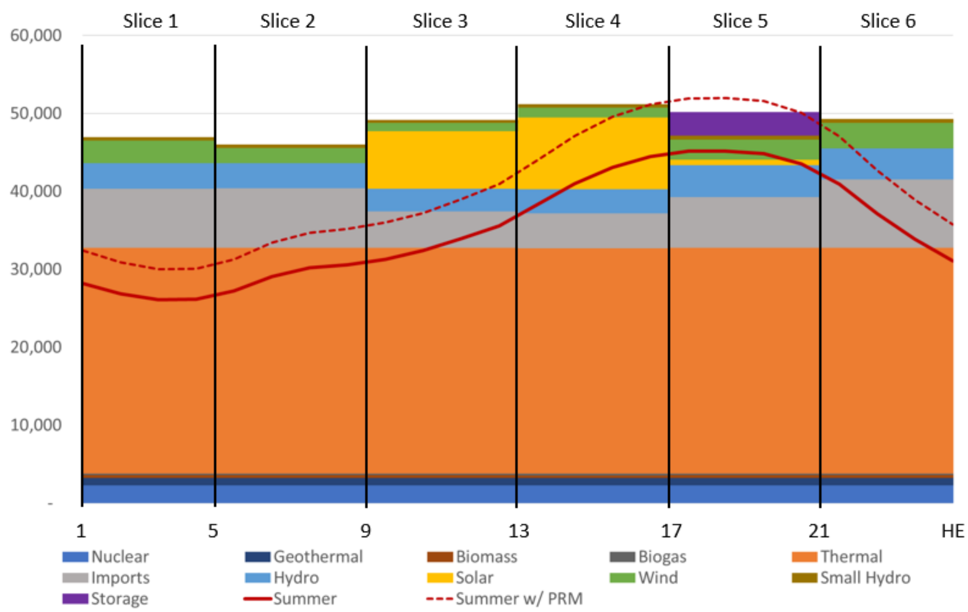
Figure 10: Resource Stack and Load Curve



framework fit together. The graphs use the 2021 CEC hourly forecast, 2018-19 CAISO production data, and 2021 NQC data to generate draft requirements and resource stacks. The graphs are intended as examples and not PG&E's position on how all the pieces should come together. The graphs use a sample summer season (June – September) for the load (solid red lines), with a sample PRM applied on top (dotted red lines). Six four-hour slices are used to accommodate storage and sample exceedance values are used for the resources (based on the 2018-2019 production data).

This graph indicates that there would be shortages in almost all slices and particularly under the sample PRM. However, the graph illustrates the problem with strictly using

Figure 11: Resource Stack and Load Curve; NQC Thermal Values and Some Storage



production data for thermal, as additional thermal is available, it just was not needed by the system. The thermal values are replaced in Figure 11. Additionally, 3,000 MWs of storage has been added to the graph as a proxy for the storage that has recently come online and the storage that is expected from the 2019 IRP procurement order. This supply stack does a better job at meeting the load and sample PRM requirement, with the exception of slice 5, when there are some shortages. However, this is not wholly unexpected given the shortages experienced in August 2020.

Lastly, PG&E has included a scenario in Figure 12 that helps illustrate the value of the Slice-of-Day framework. Nuclear has been removed, to account for the upcoming Diablo Canyon retirement, also 10,000 MWs of thermal has been removed to account for upcoming OTC retirements and potential future thermal retirements, and 10,000 MWs of storage added to replace the thermal.

Figure 12: Resource Stack and Load Curve; 10 GW of Thermal Replaced with 10 GW of Storage

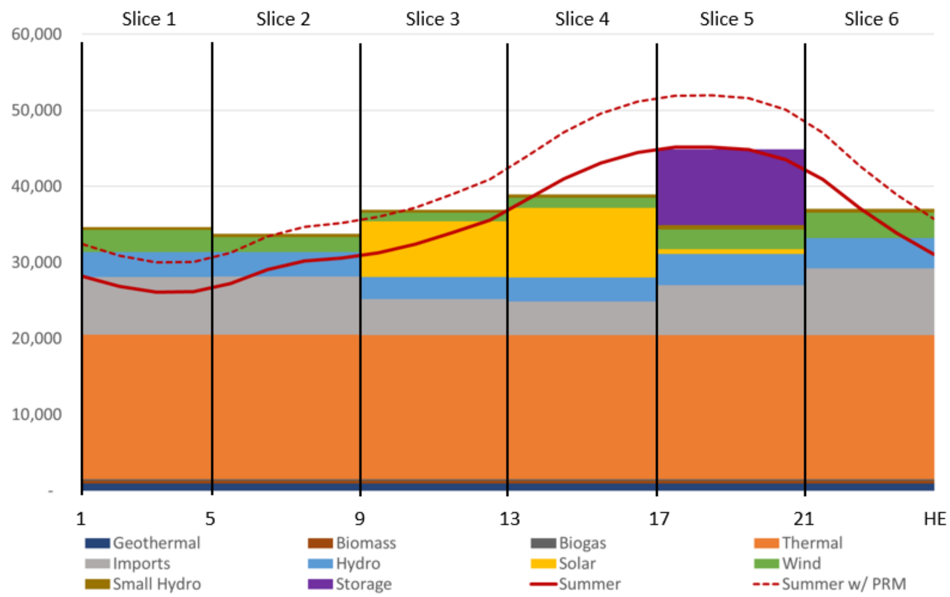


Figure 12 shows that storage is not a one-for-one replacement of thermal and that additional times could become concerning in future years when less thermal is on the system and the grid is relying increasingly on storage. While there are additional levels of solar and wind that likely should be added given the additions that are expected in the next several years, these would primarily address the shortages in slices 3 and 4. Slice 6 illustrates the need that is likely in the later evening and night-time hours – beyond the net peak load.

Finally, Figure 12 illustrates the importance of considering needs in all hours. If the solid red line were the requirement, sufficient capacity would exist above the red line in slices 1, 2, 3 and 6 to charge the storage, but the shortages in slices 4 and 6 would not be known in a system that only considers the gross peak load and net peak load.

4. **Need Determination and Allocation**

PG&E's original "Slice-of-Day" proposal noted that the approach could work with a top-down or bottoms-up requirements framework. Since filing the original proposal, PG&E has outlined some key objectives for determining need (RA requirements) and allocating those requirements to LSEs, which include:

- Administrative Complexity: The final framework should be implementable with a reasonable level of administrative effort.
- Over-Procurement Risk: The approach should minimize over-procurement to the extent possible.
- Fair Cost-Attribution: The approach should allocate requirements to LSEs that are reflective of the costs the LSE imposes on the system.
- Incentive to Flatten Load: The approach should provide an incentive to use distribution energy resources ("DER") solutions to flatten load.

PG&E looked at the available options in greater depth following the December 18, 2020 filing and has identified a third "hybrid" option that borrows elements of both the top-down and bottom-up approaches. The table below summarizes the three options PG&E has identified, from both a requirements and LSE allocation perspective. PG&E provides further detail on each option following the table.

Table 5: Need Determination and Allocation Options

		Requirements	LSE Allocation	Notes
1	**Top Down** Existing allocation approach by season	CAISO level; Set based on existing hourly forecast	Existing LSE peak monthly load shares are applied to each season	Uses existing data; easy to implement
2	**Hybrid** Allocation by LSE-specific loads in each season and slice	CAISO level; Set based on existing hourly forecast	Based on LSE-specific loads in each season and slice	Need LSE hourly forecasts; greater granularity provides equitable allocation; additional administrative effort
3	**Bottoms Up** Different LSE seasons and slices	LSE level; Seasons and slices set based on load and resource mix of each LSE	Allocation N/A; Need to confirm that aggregated requirements meet system needs	Need LSE hourly forecasts; differing seasons / slices across LSEs would be administratively burdensome

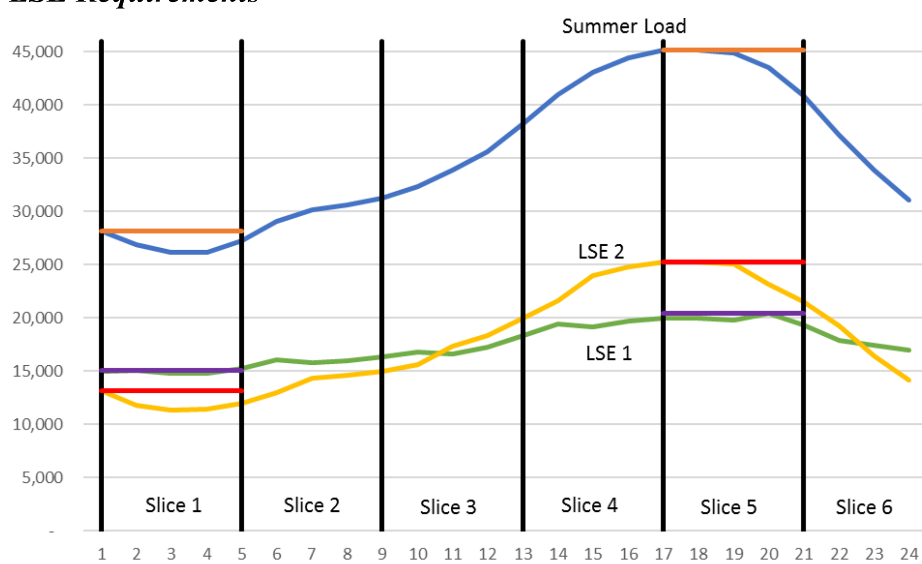
a. Top Down

Under the top-down approach, system requirements are established using the CAISO-level hourly forecast, a forecast that the CEC already produces. Requirements for each season and slice are then allocated to LSEs using existing peak monthly load shares. Effectively this means that LSEs are allocated their share of each season and slice requirement based on a monthly coincident peak load share. This approach requires no changes to how allocations are currently done.

b. Hybrid

The hybrid approach borrows some elements of a top-down approach and a bottoms-up approach. The overall system requirement is still set at the CAISO level using the existing CEC hourly forecast. However, LSE allocations would change to be based on LSE-specific loads in each season and slice. This is illustrated in Figure 13 in which a theoretical system composed of two LSEs with 50 percent of the total energy, but in which one has a flatter load curve and one has a peakier load curve. The requirements at both the system and LSE level would be set at the highest point in each slice, illustrated by the horizontal lines in slices 1 and 5. Such an approach uses elements of the top-down (setting the overall system requirement using the CAISO-level forecast), as well as the bottoms-up (allocating LSE requirements based on hourly load data for each LSE in each slice). The approach does require more granular LSE-level forecasts (or an approach to approximate load shares), which does not currently exist and would need to be developed.

Figure 13: Illustrative Example of Determining System Need and Allocating LSE Requirements



c. Bottoms-Up

The bottoms-up approach starts at the LSE level with LSE hourly load forecasts and then aggregates up the system level. PG&E has defined the bottoms-up approach as using different seasons and slices. This is because a bottoms-up approach that uses the same seasons and slices would end up with a result similar to the hybrid approach, but through a much more laborious process. Therefore, a bottom up approach using different seasons and slices would use each LSE's load curve and resource mix to establish the best seasons and slices for that LSE. It would then aggregate the various LSE season and slice determinations up to a system level. Because the approach does not start with the overall CAISO system need, there would need to be a check to ensure that the aggregated forecasts and seasons / slices meet overall system needs. A system would also need to be put into place to correct deficiencies should aggregated results not be sufficient to meet system needs. This approach would require LSE hourly forecasts.

d. Discussion

PG&E supports the hybrid approach as the best approach for meeting the four objectives identified above. The bottoms-up approach using different seasons and slices would be administratively burdensome to implement and oversee; it would also complicate transactions, as resources would not be able to offer standard season and slice products. The top-down approach, while easy to implement, does not fairly allocate costs between LSEs and could adversely impact an LSE's incentive to flatten load. The hybrid approach offers a middle ground that reasonably meets all four objectives. The hybrid would require more granular LSE forecasts, but a simpler approach of using prior year interval data to establish the load shares in each season and slice could be pursued. Interval data is already available to the Energy Division to perform such a validation on the allocations.

5. Must-Offer Obligation

In PG&E's original "Slice-of-Day" proposal, PG&E indicated that the MOO would:

- Apply to <u>both</u> day-ahead and real-time markets and only apply to the slice-of-day the resource was counting for RA.
- Storage resources would commit to charging during a specific slice-of-day and provide capacity to produce energy during that slice.

Since the original proposal, PG&E has decided to amend its proposal to incorporate feedback from stakeholders. Stakeholders expressed concerns regarding the requirements for charging storage may run afoul of the CAISO's energy market optimization and could place burdensome requirements on the operation of storage devices.

This would change the MOO to only apply to the day-ahead market and change the storage requirement to allow for charging during other slices. The revised changes are:

- MOO would still only apply for the slice-of-day the resource was counting for RA but would only be applicable to the day-ahead market. Since the CAISO's day-ahead market optimizes for all 24 hours of the day at once, the resulting charging-discharging schedule should be feasible.
- Storage resources would be still be linked to capacity to produce energy during another slice-of-day, but the storage device would not be required to charge during that slice, but could charge during any slice it was not counting for RA. This would allow freedom for storage resources to deviate from their day-ahead schedules for charging should real-time prices provide the opportunity.

Further modifications to the MOO could be possible as well. For instance, the CAISO currently has a MOO for RA resources for bidding in all hours of the day. This could be carried over into the slice-of-day framework with the caveat that the resource performance would only be assessed during the slices for which it was counting for RA, and would not be penalized for periods that is was not being counted on to be available to produce.

III. CONTRACT HEDGE PROPOSALS

A. Background:

As discussed in the revised proposal, the Commission has expressed a desire to tie energy market participation to resource adequacy requirements. In the past tolling arrangements provided this tie although tolling arrangements were never required in order to meet RA obligations. In its December proposal, PG&E outlined a contract rebate mechanism that could be used to provide incentives to generators to participate in the energy market. PG&E received feedback on this mechanism through individual meetings with parties, filed comments, and at the February 8th workshop. At the February 8th workshop, PG&E presented its original proposal and an alternative contract hedge proposal to address stakeholder feedback. PG&E provides below a summary of the feedback on the original proposal as well as a fuller description of the alternative proposal.

B. Variable Cost Hedge Proposal

1. Proposal as outlined

The Commission would require all RA contracts to identify the variable operating costs (or relevant proxy) of the RA resource and require a rebate of energy market revenue in excess of those costs. For example, a thermal unit's cost would include: fuel, variable operations and maintenance, and emissions costs, which would be specified in the contract. The contract would also specify a rebate mechanism to have the seller rebate to the buyer the difference between the resources' locational marginal price ("LMP") and these variable costs whenever the price is above the costs whether the resource produced energy or not. This would provide an incentive for the resource owner to bid the resource at these variable costs. If prices are below the variable costs, the unit would not run and no rebate would be paid. Similar incentives can be included for other types of resources. The Commission would require these terms for RA contracts.

2. Feedback on Variable Cost Proposal

In comments on proposals filed on January 15, there were several comments made on this proposal. Some of these concerns are list here.

One concern expressed that this is an administratively heavy approach to providing an incentive to bid in the energy market. This observation has merit as implementing this approach would require LSEs to get comfortable with the cost components of each resource it contracts with. Similarly, under this approach, Energy Division would have the burden to check whether the terms of contracts, including the cost specifications, were compliant with this rebate requirement.

Another concern was that setting marginal costs for some resources could be difficult and not easily captured in straight forward terms. This may be the case for resources with use limitations such as limited fuel, or operating restrictions that are not easily verified.

Concerns were also expressed that this type of mechanism leaves the seller with operating risks associated with the cost parameters being different than specified in the RA contract. Given that the resource owner and operator are better suited to manage those risks it is probably appropriate that such risk should be borne by the resource owner. Of course, the seller would have the opportunity to recover the costs of bearing such costs in the upfront RA contract.

Parties also pointed out that this approach would require renegotiation of most current RA contracts. This is also an accurate observation since it is unlikely that existing contracts have these provisions. This was one of the reasons why a PG&E in the original proposal suggested a transition mechanism so that a gradual adoption of this requirement would allow new contracts to include these provisions, but not necessitate the renegotiation of all RA contracts.

C. Price Cap Rebate Proposal

1. Energy Division Proposal

In Track 3B.2, Energy Division proposed a bid-cap mechanism that would require all RA contracts to require resources to bid into the energy market no greater than the higher of $300/MW hour ("MWh") or the resource's default energy bid as defined by the CAISO.[6] PG&E's comments in response to the Energy Division's proposal on a bid cap suggested considering an alternative to the bid cap approach that would require a rebate-type of mechanism like PG&E's contract hedge proposal.

2. Modification for a Price Cap Rebate

PG&E believes this approach would meet the objective of limiting market power while enabling more efficient administration of compliance with the requirement. This mechanism would work the same at the hedge proposal above, but instead of having the rebate trigger and amount be based on the specified variable cost in the contract, it would be based on a price cap value. Consequently, whenever the LMP for the resource were to go above the trigger value, a

[6] Addendum to Energy Division Issue Paper and Draft Straw Proposal for Consideration in Track 3B.2 of Proceeding R.19-11-009, filed December 18, 2020, pp. 15-16.

rebate would be paid by the resource to the LSE for an amount equal to the quantity of the contract times the difference between the LMP and the price cap value.

a. Example of Price Cap Rebate Mechanism

Specifically, the rebated amount = MW * (LMP – Price Cap), if LMP > Price Cap. If the LMP is below the price cap, then no rebate would be paid. As an example, assume the price cap is $500/MWh and contract is for 50 MW. If the LMP is, say, $550/MWh, the rebate would be 50*($550 -$500) = $2500. Similarly, if the LMP is, say at $450/MWh, there would be no rebate.

b. Hedge Provided by Price Cap Rebate Mechanism

This mechanism assures that energy prices above the price cap amount do no additional harm to consumers, and that resources do not directly benefit from energy prices above the price cap. This mechanism will not assure that resources will bid their variable costs, but it does provide a price hedge to consumers that they will not be harmed by prices above the price cap. The Commission could require contracts that include this rebate mechanism. The price cap could be left to LSEs to negotiate with direction from the Commission that it cannot exceed a specific value. This will allow LSEs to determine how much of a price hedge would be provided by this mechanism. However, requiring this price cap rebate mechanism would combine capacity with a price hedging and the upfront contract cost would be dependent on the level of hedging provided. Contracts with lower price caps would demand more upfront contract payments due to an expectation of more rebates. Alternatively, the Commission could require that the price cap amount be the same for all RA contracts.